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Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding

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Table of Contents

List of Tables and Figures ii

Introduction 1

- Overview 1
- The REV Proceeding 2
- Benefit-Cost Analysis 3
- Principles of the BCA Framework 3

Role of the BCA Framework in REV Implementation 5

- Areas Where the Proposed BCA Framework Should Be Employed 6
- Utility Implementation of the BCA Framework 8

Benefits and Costs Included in the Proposed Framework 11

Proposed Methodology for Valuing Benefits and Costs 13

- Valuing Benefits 13
  - Avoided Generation Capacity (ICAP) Costs, including Reserve Margin 13
  - Avoided Energy (LBMP) 15
  - Avoided Transmission Capacity Infrastructure and O&M 17
  - Avoided Transmission Losses 18
  - Avoided Ancillary Services 18
  - Wholesale Market Price Impacts 19
  - Avoided Distribution Capacity Infrastructure 20
  - Avoided O&M Costs 24
  - Avoided Distribution Losses 25
  - Net Avoided Restoration Costs 28
  - Net Avoided Outage Costs 28
  - Externalities 29
  - Net Non-Energy Benefits 41
- Valuing Costs 42
  - Program Administration Costs 42
  - Added Ancillary Services Costs 42
  - Incremental T&D and DSP Costs 42
  - Participant DER Costs 43
  - “Lost” Utility Revenues 43
  - Utility Shareholder Incentives 43

Net Non-Energy Costs 44
Conclusion 45
Appendix A: Proposed ICAP Spreadsheet Model A-1
Appendix B: Marginal Cost Studies B-1
Appendix C: Technical Explanation of EPA-Based Marginal Damage Cost Calculation (Approach #2) C-1
Social Cost of CO_2 .... C-1
Health Impacts of SO_2 and NO_x C-2
Estimating the Total Cost per MWh C-5
References C-6

List of Tables and Figures

Table 1: List of Benefits and Costs Components to be included in BCA Framework 12
Table 2: Illustrative Example of the Avoided T&D Infrastructure Calculation 24
Table 3: Line loss as a percentage of energy delivered on various system components in Con Edison's 2007 Electric System Losses study 26
Table 4. Allowance Price Forecasts Assumed for 2014 CARIS LBMP Estimates (Nominal $/Ton) 33

Table C-1. Social Cost of CO_2, 2015-2050 a (in 2011 Dollars per Metric Ton of CO_2) C-7
Table C-2. Gross Monetized Environmental Externalities C-8
Table C-3. Net Monetized Environmental Externalities C-9

Figure 1. Effect of Reducing Bulk Requirements on Bulk CO_2 Emissions 38

Introduction

Overview

In its Order Adopting Regulatory Policy Framework and Implementation Plan[1] (the Framework Order), the Public Service Commission (the Commission) directed Department of Public Service Staff (Staff) to develop and issue a Benefit-Cost Analysis (BCA) White Paper describing a framework for considering utility proposals within the Reforming the Energy Vision (REV) proceeding and related proceedings. As noted by the Commission:

> The focus of our BCA framework development will be on four categories of utility expenditures: (i) utility investments to build [Distributed System Platform (DSP)] capabilities;[2] (ii) procurements of [Distributed Energy Resources (DER)] via selective processes; (iii) procurement of DER via tariffs; and (iv) energy efficiency programs. The extent to which BCA can be formulaically applied will depend on the type of activity and the range and time frame of potential benefits and costs. (Framework Order, p. 123)

In accordance with that direction, Staff submits this White Paper, which presents a proposed benefit-cost analysis framework and proposed guidance on key parameters included in that framework. An underlying objective of this White Paper is to facilitate a dialogue among parties addressing the components and application of a BCA in the context of REV. To that end, Staff looks forward to receiving comments on all aspects of the White Paper, and specifically invites attention to the questions of 1) what analytical components should be included in a BCA, 2) the method for determining the value of the component, 3) the frequency of updating such values, and 4) the approach to applying the BCA in specific applications.

This White Paper begins by explaining the need for the development of a BCA framework within the REV proceeding. It then discusses how the BCA framework will be employed by the utilities in implementing REV programs and policies. The White Paper next lists proposed components of the framework and provides suggested guidance on calculating the values of those components.

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1 Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015).

2 With respect to investments to build DSP capabilities, the Commission noted that it is necessary to consider the risks of inaction, and that it is particularly difficult to analyze the future benefits of innovation. Hence, the Commission concluded that evaluations regarding these types of costs “will continue to require the exercise of informed judgment.” Id, at 123.

The Framework proposed herein is intended to address the marginal costs and benefits of DER versus traditional utility investments and expenditures to be proposed in near term Distributed System Implementation Plans (DSIPs) and tariff development. At the same time, other REV initiatives endeavor to reform traditional utility decision-making by modifying ratemaking and utility incentives to grow markets and improve system efficiencies. This Framework, and utility applied BCAs, should also adapt and evolve to reflect new market structures, products, and services as they develop.

The REV Proceeding

The REV proceeding envisions the transformation of electric distribution utilities from serving unmanaged loads, using traditional infrastructure, to dynamically managing a platform that provides ratepayers with the greatest benefits at the lowest cost, while also maximizing consumer options. An important goal of REV is to maintain system reliability in a manner that reflects both cost reductions and net benefit gains. The Commission concluded in the Track 1 Order that the case for the REV policy framework is compelling, as compared to the business-as-usual approach. The Commission explained that system efficiency and benefits could be improved, and costs reduced, by specifically valuing, and providing appropriate compensation for, behind-the-meter generation, active load management, and conservation. This is clearly superior to treating these DER as uncontrollable factors that—like weather and the state of the economy—affect hard-to-predict, “price inelastic” load. Similarly, recognizing and evaluating new opportunities to harness DER to improve system efficiency is clearly superior to ignoring them. The Commission recognized that an accurate and consistent analysis methodology would be required to consider and compare these opportunities. The Commission recognized that the application of a BCA methodology can ensure that these opportunities and technologies are subject to consistent and accurate consideration and that ratepayer funds are employed in the most efficient manner. To that end, the Commission directed Staff to prepare a proposed BCA framework for review and comment by interested parties. This White Paper responds to that assignment.

Benefit-Cost Analysis

In a general sense, a BCA is the careful comparison of the positive and negative consequences of a potential action. In its most specific sense, BCA is the systematic quantification of the net present value of an action under consideration. The specific action considered can be an investment, a purchase contract or portfolio, alternative tariff designs, or alternative operating procedures. Businesses, including utilities, engage in some form of BCA continuously for all manner of decisions and analyses, at different levels of complexity depending on the significance and time-frame of the action. When needs are immediate and benefits obvious and large relative to costs, such as in the case of immediate restoration after an outage, no formal BCA is required. On the other hand, the more that time allows for the consideration of alternative courses of action, and the more quantifiable the costs and benefits, the more specific and granular the BCA should be. The development of a BCA must address both the selection of elements that comprise the components of the BCA as well as how the application of the components will vary in specific settings.

Principles of the BCA Framework

Staff developed the proposed BCA framework based on the following principles. BCAs performed for REV projects should:

- Be transparent about assumptions, perspectives considered, sources, and methodologies;
- List all benefits and costs borne by all parties, including localized impacts on host communities;
- State which benefits and costs are not included or quantified in the overall BCA and why;
- Not unnecessarily combine or conflate different benefits and costs;
- Be designed to assess portfolios, rather than individual measures or investments, to allow the consideration of potential synergies and economies between resources or measures;[3]

[3] Although it may be appropriate to allow different scales of portfolios. For example, for utility investment plans, the BCA assessment should be performed at the implementation plan level, not at the specific grid investment level, if doing so reflects overall economies not reflected at the individual investment level.

- Reflect the expected level of DER penetration[4] for the relevant time periods considered;
- Be a full-life-of-the-investment analysis and include a sensitivity analysis on key assumptions;
- Assess the benefits and costs of investments in comparison to a reasonable traditional or "business-as-usual" case rather than in isolation;
- Strive to improve the granularity--that is, the locational and temporal specificity--of the valuation of the benefit and cost components, especially for those at the distribution level;
- Report results of the Societal Cost Test (SCT), Utility Cost Test (UCT), and Rate Impact Measure (RIM);
- Allow for judgment, such that if investments do not pass cost tests based on included quantified benefits, a qualitative assessment of non-quantified benefits may be appropriate to inform approval; and
- Balance the interest in providing a stable investment environment for supporting the DER market, with the need to be sufficiently adaptive so that benefit and cost valuation does not become outdated and inaccurate.

Parties are invited to comment on the appropriateness of these principles and whether the list should include other principles.

[4] The benefits and costs of DER will change based on the extent of DER penetration. This becomes more significant as the level of DER penetration increases. For efficient levels resource acquisition, the effect of DER procurements on benefits and costs should be accurately reflected,

Role of the BCA Framework in REV Implementation

This BCA framework has been designed to inform certain specific aspects of utility planning and decision-making in implementing REV, which are described below. Utilities following the framework will make decisions in a transparent manner, allowing DER providers and customers to predict and understand the products selected and incentives provided.

This framework follows the familiar approach of valuing alternative resources by focusing on the traditional costs that can be avoided. Many of the elements described below will be familiar to those who have participated in, for example, benefit-cost proceedings for Energy Efficiency programs, in particular, those components related to bulk level energy and capacity costs. However, the goals of REV require a much more sophisticated approach to valuing the distribution level components of avoidable costs than has been applied in the past. This document was developed primarily to inform the initial DSIP filings and applications, which will describe each utility's system needs, potential capital expenditure plans, plans to solicit alternative resources to meet those needs, and then selecting among those alternatives in the most beneficial and efficient manner.

That is only the first step in implementing REV. As discussed below, the benefit and cost categories described herein should be generally relevant in another early step: developing tariffs to value behind-the-meter resources and demand response. But improving the transparent valuation of the distribution system, and the value of distributed resources and load management, does not end here. Technological advances in 1) distributed resources and 2) information and communication technologies will both allow and require more dynamic and granular methods for valuing distribution level benefits and costs. Even as this document's framework is proposed, debated, modified and implemented, a tremendous amount of increasingly sophisticated research and development work is being conducted by the utilities, DPS Staff, consultants, and other parties related to this issue. While this is also among the issues discussed in Track 2, developing more dynamic and granular methods for determining the marginal value of resources at the distribution level will require a continuous process rather than a single decision by the Commission.

Areas Where the Proposed BCA Framework Should Be Employed

This White Paper addresses a specific and quantifiable portion of REV implementation—the evaluation of opportunities to avoid traditional utility distribution investments by calling upon the marketplace to supply DER alternatives. These opportunities will be identified in each utility's Distribution System Implementation Plan (DSIP). The subsequent procurement and investment alternatives must be compared to each other. In these implementation analyses, the utilities will be called upon to: identify ways that various DER alternatives can be substituted for traditional grid-based solutions; compare the costs of DER to the costs of traditional grid-based solutions; and compare the costs of alternative DER solutions to each other. These analyses must include consideration of social values (sometimes called external costs and benefits), quantifiably when possible and qualitatively when not. Alongside pecuniary cost and system efficiency benefits, the utilities will be called upon to compare the relative environmental impacts of DER and traditional solutions, as well as the different impacts of specific DER alternatives. Finally, the BCA should be a full life-cycle analysis, reflecting the expected lives of the measures and the associated expected reliability characteristics. As has been the case elsewhere,[5] this will often require a methodology of "stacking" alternative resources with different characteristics into a portfolio that satisfies the need in aggregate.

The BCA framework will also be used to support the development of tariffs that place a value on DER, including an implied value inherent in a retail rate that can be avoided and an explicit valuation that gets applied as a separate credit. Such tariffs should reference the BCA framework and give due consideration to all of the categories of benefits and costs identified. However, tariffs should not be required to be based on strict application of the BCA framework since tariffs, in general, are different instruments than investments or longer term procurements. Investments and longer-term procurements require long-term forecasts and assumptions, while tariffs and other dynamic price signals must reflect more near-term assessments of value and system

[5] Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program, Order Establishing Brooklyn / Queens Demand Management Program (issued December 12, 2014).

conditions. For example, in this framework, we propose the use of Location Based Marginal Prices (LBMP) forecasts from NYISO's Congestion Assessment and Resource Integration Study (CARIS) to value the avoided system energy on a long term basis. However, a dynamic tariff should be based on actual LBMPs, as the Mandatory Hourly Price retail rate tariffs are.[6] This permits tariffs to efficiently and reliably balance the system that develops around, and in response to, the long-term investments and procurements made. Similarly, the value of avoiding distribution level capacity costs will decline as resources are added to a constrained local area. When comparing portfolios of different quantities of various resources in a long term procurement setting, utilities can make adjustments to valuations to account for this. Dynamic tariffs, on the other hand, may need to be self-adjusting or have limitations or other mechanisms to address this concern. Further, different tariffs will be developed to address different needs. Those issues should be addressed in the development of specific tariffs with full knowledge of, and reference to, the BCA framework discussed here.

This White Paper describes the general components of value that DER can provide to the electric system, and proposed methods for quantifying them. It does not propose processes, incentives, rules, or tariffs for opening up the utility system to competitive alternatives. Such processes will be developed in related REV initiatives and collaboratives. Staff's DSIP Guidance filing will discuss the recommended contents of these utility proposals for comparing alternative resource solutions, including the process for assuring fair, open, and value-based decision-making, as utilities identify and develop opportunities that can be open to third-party sourcing. The BCA Handbooks, recommended herein, will increase the transparency of the utility decision-making process further. Staff's Track 2 White Paper will discuss the development of tariffs that recognize the full value of DER alternatives, propose certain incentive mechanisms to promote the development of a more competitive "Behind-the-Meter" market, and address customer and system data access issues for DER and ESCO

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[6] As discussed throughout this document, and elsewhere, dynamic and granular valuation of resources at the distribution level will require much more than dynamic LBMPs. For example, see Tufon, Christopher, A.G. Isemonger, B. Kirby, J. Kueck, T. Li, A Tariff for Reactive Power, Oak Ridge National Labs, ORNL/TM-2008/83, 2008; Caramanis, Michael, "Is It Time for Power Market Reform to Allow for Retail Customer Participation and Distribution Network Marginal Pricing?", IEEE Smart Grid, March 2012; and Osterhus, Tom and M. Ozog, Distributed Marginal Prices (DMPs), Update #6, Integral Analytics, 2014.

developers. The Clean Energy Fund and Utility Energy Efficiency proceedings will address the process by which utilities, and the New York State Energy Research and Development Authority (NYSERDA), transition from the status quo for Energy Efficiency and other clean energy initiatives.[7] This BCA Framework will provide the proposed components of value of DERs, and, where relevant, a consistent set of quantification methods to be used in each of the above related REV processes.

Parties are invited to offer comments addressing the use of this BCA framework in developing future tariffs to value behind-the-meter resources. Further, parties are expected to comment on how the BCA can, and should, relate to ongoing utility resource planning processes and a shift towards more open-source and dynamic methods. Parties are also invited to comment upon whether there are other situations where this BCA Framework should be used, as well as the implications of such application. For example, beyond the public DSIP process, parties should comment on whether this Framework should be applied by utilities in their routine asset management decision-making.

Utility Implementation of the BCA Framework

While this White Paper addresses valuation issues that will be relevant to the application of the BCA framework, not all valuation issues are amenable to a generic treatment. Where possible, a standard source is recommended for valuing a particular element. However, many costs, and thus values, at the distribution level will be specific to granular locations on each utility's system and will be need to be identified and estimated by the utilities. Similarly, costs of DER alternatives will not be known until the utilities solicit offers from the market in response to particular system needs. The first step of implementing the BCA framework will occur in the presentation of each utility's DSIP, within which each utility will present its system needs, proposed projects, potential capital budgets, particular needs or portions of needs could be met by DER or other alternative resources, and plans for soliciting such alternatives from the market.

To ensure that variations are reasonable, and that analyses and decisions are transparent, after the final BCA framework is issued, Staff proposes that each utility be

[7] Case 14-M-0094, Proceeding on Motion of the Commission to Consider a Clean Energy Fund; Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs.

required to compile, and make available to parties, a "BCA Handbook." This Handbook will describe and quantify the utility's benefit and cost components and their respective application when evaluating DER projects for possible development. While Staff envisions that the contents of the Handbook and the process, including its updating will be included in each utility's DSIP, the process for issuing and updating the Handbook will be articulated as part of adoption of the BCA framework.

The value of different resource types is expected to be explicitly included in the Handbook. Effectively assessing the benefits of DERs requires accurately assessing the amount of energy, capacity, and other benefits that those resources provide, and how often, when, and where they will be provided. Therefore, for planning purposes, a methodology must be developed to: 1) characterize DER resource profiles; and 2) determine to what degree those resources reduce energy or capacity and ancillary service needs. Any synergies between resources (for example, between DG and storage resources) should be reflected in the portfolios constructed by the utilities to optimize the long term procurement and capital investment plans proposed in the DSIPs and implemented thereafter, consistent with the adopted framework and the BCA Handbooks developed. In the Handbooks, staff proposes that utilities be required to provide an example of how all benefit and cost components will be applied to an illustrative portfolio of alternative resources. We invite parties to recommend appropriate examples for this purpose, including illustrative resource combinations that may provide synergies (that is, provide greater total net benefits when combined in a portfolio than the sum of their net benefits when considered separately).

We also propose that the Handbook include a description of the sensitivity analysis on key assumptions that will be applied to the BCA. For example, this could include how the degree of relative risk and uncertainty in the various benefit and cost estimates will be considered, and how a scenario analysis will be defined, including a low case, a medium case and a high case for the various benefits and costs of the portfolio basis. We invite parties to comment on how a sensitivity analysis should be defined and conducted.

In order to establish market engagement across the state, the Handbooks should apply common analytics and framework. However, staff recognizes that a balance needs to be struck between standardized assumptions that make program-level BCA manageable and transparent, and allowing a limited amount of flexibility to recognize possibly unique aspects of certain projects or resources. Such an approach should be based on best practices from around the country, albeit improved upon and adapted to New York, and specific proposals considered by utilities. A full description of any assumptions and approaches to be used by each utility should be included in the BCA Handbook. To assist Staff and the Commission, parties are invited to comment upon the value of such a Handbook, the process and timing that should be followed by a utility to promulgate its initial and subsequent Handbooks, and the frequency that the Handbook should be updated.

Because REV's goal is to integrate DER and utility investment and operations, Staff proposes that the proper discount rate should be based on the utility weighted average cost of capital (WACC). Staff invites comment on whether a utility-specific rate, a more generic NY-wide WACC estimated rate, or some other alternative method should be used.[8] While others have argued that different discount rates should be applied to different metrics (e.g. social discount rates for the societal cost metric, WACC for the utility cost metric), staff proposes that a single discount rate be used for all metrics. This is based on the rationale that, whatever metric is used, a decision is being made on alternative utility expenditure plans, costs that are ultimately collected from ratepayers. Thus, staff's proposal is that the overall discount rate should reflect the opportunity cost of capital for such expenditures. We invite parties to comment on this aspect of the proposal.

[8] Later in the White Paper, we discuss the unique discount rate issues involved in valuing the multi-generational damage costs associated with climate change. However, once the price for CO_2 is determined, there is still the need for a more traditional discount rate to apply to the total benefits and costs of alternative resources or portfolios. The discussion above applies to this more traditional context.

Benefits and Costs Included in the Proposed Framework

Table 1 presents Staff's proposed list of benefit and cost components and indicates whether the component should be considered in each of the cost tests After adoption by the Commission, the components will eventually serve as a consistent set to be used by all of the utilities. Parties are invited to provide comments addressing whether the list of proposed benefit and cost components should be revised.

Table 1: List of Benefits and Costs Components to be included in BCA Framework

	BCA TEST PERSPECTIVE		
BENEFITS	**Rate Impact Measure (RIM)**	**Utility Cost (UCT)**	**Societal (SCT)**
Bulk System			
Avoided Generation Capacity (ICAP), including Reserve Margin	√	√	√
Avoided Energy (LBMP)	√	√	√
Avoided Transmission Capacity Infrastructure and related O&M	√	√	√
Avoided Transmission Losses	√	√	√
Avoided Ancillary Services (e.g. operating reserves, regulation, etc.)	√	√	√
Wholesale Market Price Impacts*	√	√	--
Distribution System			
Avoided Distribution Capacity Infrastructure	√	√	√
Avoided O&M	√	√	√
Avoided Distribution Losses	√	√	√
Reliability / Resiliency			
Net Avoided Restoration Costs	√	√	√
Net Avoided Outage Costs	--	--	√
External			
Net Avoided Green House Gases	--	--	√
Net Avoided Criteria Air Pollutants	--	--	√
Avoided Water Impacts**	--	--	√
Avoided Land Impacts**	--	--	√
Net Non-Energy Benefits (e.g. avoided service terminations, avoided uncollectible bills, health impacts, employee productivity, property values, to the extent not already included above)**	√**	√**	√**
COSTS			
Program Administration Costs (including rebates, costs of market interventions, and measurement & verification Costs)	√	√	√
Added Ancillary Service Costs	√	√	√
Incremental Transmission & Distribution and DSP Costs (including incremental metering and communications)	√	√	√
Participant DER Cost (reduced by rebates, if included above)	--	--	√
Lost Utility Revenue	√	--	--
Shareholder Incentives	√	√	--
Net Non-Energy Costs (e.g. indoor emissions, noise disturbance)**	--	--	√

* See discussion on pp. 14-15.
****** These are very item- and project-specific; see discussion in the text at p. 39.

Proposed Methodology for Valuing Benefits and Costs

This section of the White Paper presents Staff's proposed methodology for valuing benefits and costs. Parties are invited to comment on the appropriateness of the proposed methodologies and to suggest alternative approaches and to valuing the components of the BCA. As stated earlier, advances in both distributed resources and information and communication technologies will both allow and require more dynamic and granular methods for valuing distribution level benefits and costs. For this reason, utilities should continually enhance their modeling methodologies to allow for a more granular calculation of the costs and benefits presented below as they move beyond the initial DSIP filings.

Valuing Benefits

Avoided Generation Capacity (ICAP) Costs, including Reserve Margin

ICAP costs are driven by system coincident peak demand. Thus, this component of benefits applies to the extent to which the resources under consideration reduce coincident peak demand.[9] To forecast avoided generation capacity costs, staff proposes use of capacity price forecasts for the wholesale market. In order to ensure resources adequate to serve summer peak loads for the New York Control Area (NYCA), Load Serving Entities (LSEs) are required to procure sufficient Installed Capacity (ICAP) to meet their forecasted summer peak loads, plus an Installed Reserve Margin determined annually by the New York State Reliability Council. In addition, LSEs serving load in several "localities" (New York City (NYC), Long Island (LI), and the "G-J" region covering NYC and Lower Hudson Valley (also called the New Capacity Zone or NCZ)) are required to obtain a portion of their capacity requirements from resources located within those localities. The minimum Locational Capacity Requirements (LCRs) are determined annually by the New York Independent System Operator (NYISO). To enforce resource adequacy requirements, the NYISO operates monthly spot auctions for NYCA and the localities; the NYISO also operates forward

[9] Avoided distribution costs, discussed below, will be related to demand reductions correlated with peaks that drive system needs at more granularly local portions of the distribution system.

auctions (monthly and 6-month strip auctions). Depending on the amount of capacity procured in the spot auction, the NYISO may require LSEs to procure additional excess capacity as determined by the Demand Curves.

The NYISO's spot auctions determine the amount of capacity that clears, or is sold through the auction, as well as the price of that capacity based on the intersection of resource supply offers and "Demand Curves" for the NYCA and the localities. The Demand Curves specify LSE valuation of capacity that reflects the "Cost of New Entry" (CONE) at the minimum requirements, but declines gradually if additional resources are available at lower prices. The auctions adjust the resource supply and demand for forced outages, yielding prices and quantities for "Unforced Capacity" (UCAP). However, this conversion does not change the overall capacity payments (that is, UCAP price x UCAP quantity = ICAP price x ICAP quantity). The Demand Curves are developed by the NYISO with stakeholder input and approved by the Federal Energy Regulatory Commission (FERC). They cover a "capability year" from May through the following April (6 months of "summer" from May - October and 6 months of "winter" from November - April). The Demand Curves are updated every 3 years, with the most recent update covering the period May 2014 - April 2017.

To forecast capacity costs, Staff proposes forecasting the spot market demand curves and capacity resources for the summer and winter months of each capability year (May through April) without adjusting for forced outages (the ICAP prices and quantities can be converted to UCAP values if necessary). To forecast the demand curves, Staff proposes using the most recent forecasts of NYCA and locality summer peak loads from the NYISO's Gold Book, published each April, and multiplying the megawatt (MW) values by the current minimum NYCA and locality (percentage) requirements to determine the minimum requirements. To forecast the Supply Curves, Staff proposes using the summer and winter capacity forecasts from the NYISO's Gold Book, supplemented by any more recent data on expected entry and retirements. In the event that forecasted resources fall short of minimum requirements, Staff proposes that additional resources be assumed to enter at the Demand Curve reference prices, which are based on the cost of new entry (CONE).

The operation of the spot auction may be approximated by a spreadsheet calculation, which calculates the demand curves and determines the ICAP clearing prices assuming all available resources clear the market. We have included Staff's proposed spreadsheet model as Attachment A. The results provide ICAP prices and quantities at the transmission level. It should be noted that a portion of the Transmission Capacity Infrastructure costs are included in the ICAP price as zonal differences in the ICAP clearing price, and care should be taken not to double-count such costs. To the extent possible, the contribution of these avoided transmission capacity infrastructure costs to the ICAP price should be determined and included in the DSIPs and Handbooks. To avoid double-counting, such costs should not also be monetized as part of the Avoided Transmission Infrastructure Capacity measure discussed later in this document.

Avoided Energy (LBMP)

To forecast avoided system energy costs, Staff proposes use of energy price forecasts for the wholesale energy market—Location Based Marginal Prices (LBMP)—from the most recent final version of the NYISO's Congestion Assessment and Resource Integration Study (CARIS) economic planning process Base Case. CARIS is a biennial collaborative process which starts with CARIS Phase 1 (CARIS 1), where 10 year forecasts are developed to evaluate transmission congestion on the bulk power system. This is followed by CARIS Phase 2 (CARIS 2) which develops 20 year forecasts to evaluate specific resource proposals. When these forecasts are developed, the first year of the forecasts undergoes a benchmarking process based on historical actual LBMPs.

These forecasts are developed by the NYISO in collaboration with market participants in Electric System Planning Working Group (ESPWG) meetings and are publicly available. The most recent final forecasts became available in November 2013 for CARIS 1, and June 2014 for CARIS 2. The next updates of these forecasts, therefore, are expected to be available during the fourth quarter of 2015 for CARIS 1 and the third quarter of 2016 for CARIS 2.

The currently available CARIS 2 forecasts are NYISO's 20 year estimates of energy prices during 2013-2032 for each of New York's eleven LBMP zones, from what is referred to as "2014 CARIS 2 Base Case Results" ("2014 Preliminary CARIS 2 Base Case Results", 6/30/2014 ESPWG, page 27). In addition to being made available to the

ESPWG, CARIS 2 forecasts are reported to the NYISO's Business Issues Committee (BIC). While the CARIS process provides for CARIS 1 forecasts being presented in the biennial CARIS Phase 1 Report, CARIS 2 forecasts are not presented in a formal report—generally, these are reported biennially as a slide presentation to the ESPWG.

Staff proposes LBMPs from the CARIS 2 forecasts be used for the period 2014-2032. We compared year-2014 historical LBMPs to forecast year-2014 LBMPs. We found that the forecast year-2014 LBMPs more closely track historical LBMPs during April 2014-March 2015, as opposed to historical year-2014 LBMPs. This is understandable since LBMPs spiked up significantly during January-February of 2014 due to the unusual winter "polar vortex" effects and the related oil unavailability. Following 2014, policies have been implemented to ensure oil availability. As a result, we view winter-2014 price spikes due to oil unavailability as being an aberration. We believe, therefore, that the year-2014 forecast LBMPs can be considered to reasonably reflect historical LBMPs.

Additionally, to lessen year-to-year volatility in the annual forecasts, Staff proposes that consideration should be given to applying the average annual growth rates implied by the CARIS forecasts to the first relevant forecast year's estimated LBMPs (in the present case, the year-2014 forecast LBMPs) to produce smoothed-out forecasts of LBMPs for the 2015-2032 period. To extend the LBMP forecasts beyond the year-2032, if necessary, Staff proposes utilities assume the year-2032 LBMPs stay constant in real (inflation adjusted) $/MWh.[10] Historical real-time hourly LBMPs are proposed to be used to convert forecast average annual LBMPs into a forecast of time-differentiated LBMPs (for example, monthly, seasonal, or sub-period LBMPs). We suggest using historical data beginning in 2006—to capture when the NYISO began incorporating scarcity pricing provisions in LBMPs—through 2014.

Supporting our preference for utility modeling methodologies that become more granular over time, a similar approach valuing sub-zonal pricing differences could be applied to future dispatch prices of DER assets on the distribution grid. To the extent that such differences can be identified, Staff encourages inclusion of such benefits or

[10] Staff's rationale is, simply, that 2032 is so far in the future that it is difficult to argue convincingly that, beyond that date, wholesale electric energy prices will grow either faster, or slower, than the general price trend in the overall economy.

costs as distribution-level values. Staff invites parties to comment on how such sub-zonal values (for example, at the substation, feeder, transformer or customer level) might be identified and monetized.

It should be noted that the LBMP includes costs for a number of other factors: (1) compliance costs of various air pollutant emission regulations including the Regional Greenhouse Gas Initiative and now-defunct SO_2 and NO_X cap-and-trade markets; (2) transmission-level line loss costs; and (3) transmission capacity infrastructure costs built into the transmission congestion charge. To the extent possible, the contribution of these costs to the LBMP should be determined and included herein. Such costs should not be also be monetized as part of the Net Avoided Greenhouse Gases, Net Avoided Criteria Pollutants, Avoided Transmission Losses, or Avoided Transmission Capacity Infrastructure measures discussed later in this document.

Staff invites party comments on all of the above assumptions and methods proposed for the standardized estimation of avoided bulk energy costs (LBMPs).

Avoided Transmission Capacity Infrastructure and O&M

A portion of the Avoided Transmission Capacity Infrastructure and related O&M costs are included in both the Avoided Generation Capacity (ICAP) and Avoided Energy (LBMP) benefit categories. Transmission capacity and O&M costs are reflected in the difference between zonal ICAP clearing prices. Generation assets located in high load and congestion areas, such as New York City, the lower Hudson Valley, and Long Island, clear the ICAP market at a higher price in reflection of the fact that load serving entities in those areas are required to purchase generation from local assets due to restrictions on the transmission system, which precludes the purchase and transport of generation from cheaper assets further away from the load. Transmission congestion charges, related to the availability of transmission infrastructure to carry energy from zone to zone, are included in the LBMP. Both the ICAP prices and transmission congestion charges would be decreased in the event that additional transmission assets are built or load is reduced.

To the extent that there are values provided through avoided transmission capacity infrastructure and O&M beyond that which is included in the ICAP price and LBMP, such avoided costs should be considered separately herein. The sections on

Avoided Distribution Capacity Infrastructure, and Avoided T&D O&M, below, describe how these avoided costs should be monetized in general. The remaining Avoided Transmission Capacity Infrastructure and O&M beyond those captured in the Avoided Generation Capacity (ICAP) and Avoided Energy (LBMP) benefit categories should be calculated in the same manner as that employed for determining avoided distribution capacity infrastructure and avoided O&M. Avoided Transmission Capacity Infrastructure and O&M benefits specific to each utility should be included in individual utility DSIPs and Handbooks.

Avoided Transmission Losses

A portion of the Transmission Loss costs are included in the LBMP, and are therefore partially counted already through the Avoided Energy (LBMP) benefit category as part of the costs included in the LBMP. To the extent that there are avoided transmission losses above and beyond what is included in the LBMP, such losses should be considered separately herein. The section on Avoided Distribution Losses, below, describes how losses should be monetized in general. The remaining Avoided Transmission Losses beyond those captured in the Avoided Energy (LBMP) benefit should be calculated in the same manner as that employed for determining distribution line losses. Avoided Transmission Loss benefits specific to each utility should be included in individual utility DSIPs and Handbooks.

Avoided Ancillary Services

Required ancillary services, including spinning reserve, frequency regulation, voltage support and VAR support would be reduced if generators could more closely follow load. Certain projects will enable the grid operator to require a lower level of ancillary services or to purchase ancillary services from sources other than conventional generators at a reduced cost without sacrificing reliability. For example, to the extent that reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, storage and distributed generation with sensors, controls, and communications systems can be better coordinated to reduce load, ancillary service costs for voltage and VAR support could be reduced, decreasing the cost for market participants and utilities. While this benefit may be hard to forecast because ancillary services vary significantly from year to year and are market based, parties are invited to comment on how such a forecast could be done. The Avoided Ancillary Services benefits are likely to be highly project-specific, and methods for their valuation should be included in utility DSIPs and Handbooks.

Wholesale Market Price Impacts

Wholesale market price impacts differ from the avoidable ICAP and LBMP costs discussed above. The latter refer to so-called resource cost savings—that is, the extent to which a 1 MW reduction in customer load on the system reduces the need to generate, transmit, and backup the power to meet that 1 MW of load. Wholesale market price impacts refer to the possible reduction in prices paid in the market caused by an initial reduction in load, multiplied by the entire quantity of purchases expected at this lower price level. Often, estimates of wholesale market price impacts exceed resource cost savings by orders of magnitude. Because these estimated price impacts are more of a transfer payment (a shifting of dollars) from generators to consumers, but not a resource efficiency gain,[11] they are only included in the RIM and Utility Cost metrics, not in the Societal Cost metric.

While changes in electricity usage could result in reductions in the wholesale market price of electricity in the near-term, it is difficult to accurately predict by how much, for how long, and to what degree of variation across regions and locations those reductions exist. For instance, estimates of wholesale energy market price impacts associated with wholesale demand reductions (for example, those resulting from behind-the-meter DER) are typically made using non-dynamic electricity market simulation models, such as the MAPS model used for CARIS or the ICAP forecasting model based on fixed Gold Book projections.[12] Such static estimates, by nature, do not reflect (a) many anticipatory responses by the supply side to announced policy changes; or (b) subsequent responses to short-term price reductions on both the supply and demand sides of the market. There are a number of reasons why often-cited price reduction benefits would be fleeting, if they exist at all, as the supply and demand sides

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[11] The efficiency gains (the so-called “resource cost savings”) have already been reflected in the LBMP savings, discussed above.

[12] Further, such models will overstate wholesale price impacts simply because these models do not reflect the many hedge contracts that LSEs have to limit the exposure of their customers to near term market price impacts.

of the market continuously adjust. Lower market prices are passed on to consumers—to many customers almost immediately—and these lower prices will stimulate increases in demand, and thus prices. Planned investments and upgrades on the supply side, or behind the meter, may be reduced, put on hold, or cancelled, reducing the "but-for" supply, thus offsetting any modeled price reductions. In recent years, New York has seen significant amounts of generator mothballing, and reopening, demonstrating significant price elasticity on the wholesale supply side.[13] As REV proceeds, we expect a more price elastic demand side of the market as well.

In sum, Staff recognizes the controversial nature of including price reductions as benefits. Nonetheless, it is impossible to say that there will be zero wholesale price impacts, at least in the short run. Parties are encouraged to comment on the appropriateness of, and alternatives to, the following possible approximation methods:

(1) Staff uses the CARIS database to estimate wholesale market price impacts for a very short period (for example, one year), reduced for an approximate % that represents near-term wholesale price hedge contracts;

(2) Staff uses the CARIS database to estimate wholesale price impacts for a longer period (for example, three years), but phases the effect out over three years as follows: 100% for year one; 50% for year two; and 25% for year three. Each of these year's effects would also be reduced to reflect hedge percentages, as above; or

(3) Each utility estimates the wholesale price effect for the projects it evaluates, including the length of time for such impacts, as well as the impact of price hedges such as contracts and TCCs, and provide these estimates, including all support (e.g. any econometric modeling used), in its DSIP filing for stakeholder comments.

Avoided Distribution Capacity Infrastructure

A utility's decision of what infrastructure to invest in, and when to make that investment, is generally driven by two factors: first, its need to meet the peak demand placed on its system; and second, the amount of available excess capacity on its

[13] It is difficult, but possible, to investigate alternative methods for modeling such supply responses to price impacts, and to reflect near term hedges, to try to improve the estimation of such price impacts. However, such a potential analysis is beyond the scope of this paper.

system. The importance of these factors can vary depending upon the voltage at which an incremental load is connected to the utility grid. Traditionally, avoided transmission and distribution (T&D) infrastructure need is considered on a system average basis and is estimated as a single dollar-per-kW value. However this estimation may significantly over- or under-value load modifications. Detailed marginal cost of service studies are necessary to fully determine the value of incremental or avoided T&D infrastructure needs. With this goal in mind, in its Order Instituting Proceeding Regarding Dynamic Load Management and Directing Tariff Filings, issued December 15, 2014 in Case 14-E-0423, the Commission directed New York State utilities to design programs that reflect the marginal cost of avoided T&D investments, granular to the network or substation level, if possible, as well as granular load information at the same disaggregated level.

On June 17, 2015 the Commission adopted the proposed DLM tariffs with modifications, Case 14-E-0423, et al. Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs, Order Adopting Dynamic Load Management Filings with Modifications (Issued and Effective June 18, 2015) for programs to be effective July 1, 2015. Utilities should include the most up-to-date version of these data in their DSIP filings. For illustrative purposes, the results of the latest marginal cost of service study performed by Con Edison are included in Appendix B: Example Marginal Cost Study.

Generally speaking, the primary driver of incremental need for T&D investment is additional incremental load during a single hour of system peak demand. However, need for marginal investment in the utility's T&D system can change based upon where load is interconnected. For example, the need to upgrade a transmission line primarily depends upon whether incremental load occurs during the single peak demand hour placed on the transmission system, whereas the incremental need to build additional secondary cable lines may be more dependent upon a new customer's peak demand, and less on its coincidence with the utility system peak demand. When estimating the value of a load addition or reduction, whether or not such load would actually trigger additional infrastructure need should be considered based on the characteristics of the specific load, and its relation to the design criteria of the utility equipment that serves it. Staff invites parties to comment on the need to standardize the level (for example, primary/secondary feeder) at which consideration of coincidence of demand shall be considered and possible approaches to apply to address this issue.

The incremental need for investment in the T&D infrastructure is also driven by the current amount of excess capacity available on the system. Incremental load has a greater potential cost in areas of the utility T&D system which are already near, at, or above their design criteria compared to incremental load in areas where excess capacity is available. That is, the addition of load in areas with little excess capacity will cause the utility to invest in T&D infrastructure sooner than if the same incremental load were to be connected in an area of greater excess capacity. Similarly, load reductions will provide a large benefit in areas of the utility T&D system with little excess capacity compared to load reductions occurring in areas where greater excess capacity is available. That is, a reduction in load in an area which is near, at, or above its design criteria may allow the utility to defer needed investment whereas a similar load reduction in an area of greater excess capacity may have no impact on T&D costs. When estimating the value of a load addition or reduction, the amount of excess capacity in the area which the load is interconnected should be considered provided that appropriately disaggregated data is available.

The voltage at which a load addition or reduction is interconnected is another factor which can influence the value of T&D investment related to a load addition or reduction. Generally speaking, load additions or reductions connected to the utility system at high voltage will not affect the need for lower voltage infrastructure, whereas the same load addition or reduction connected at a lower voltage may have an effect on the need for infrastructure investments at both lower and higher voltages. When estimating the value of a load addition or reduction, the voltage at which such load is connected, and whether it will affect the need for additional infrastructure at other voltage levels, should be considered.

Utilities should include sufficient information in their DSIPs and BCA Handbooks to inform the developing DER market of system conditions, needs, and granular marginal values so that any solicitations for alternative solutions will be robust. Parties should recommend the types and detail of information required in these documents to provide such sufficient information. To the extent that critical infrastructure information must kept confidential, utilities and parties should propose methods of information exchange that will serve the interest of increasing system efficiency while maintaining security.

A simple example of calculating the avoided distribution capacity infrastructure cost is provided below.

EXAMPLE: Battery Energy Storage located at a Con Edison Area Substation

A 1 MW battery with a 5-year service life is attached to an area substation in the Con Edison service territory. The battery is operated to reduce the peak load experienced by the area substation between 6 pm and 8 pm, whereas the system peak generally occurs at 4 pm. What is the value of avoided T&D infrastructure need for 2016?

First, we consider whether the load reduction of the battery aligns with the cost drivers of the utility equipment which it is connected to. In this instance, operation of the battery does reduce demand during the peak hours experienced by the area substation, but not those of the system as a whole. Further, since the battery is connected directly at the area substation, for simplicity we assume its operation does not decrease peak load on Con Edison's primary or secondary distribution feeders. Therefore, we may only consider the battery's contributions to avoided Area Station and Subtransmission Costs.

To determine the value of avoided T&D for the battery, we multiply the amount of load reduction caused by the battery by the marginal costs of the equipment that the load is being relieved from; this calculation should be done for the entire service life of the battery (calculations for 2015 and 2016 have been shown as a demonstration).

$$\text{Avoided T\&D}_{2015} = \text{load reduction} * \text{marginal cost}_{2015}$$

$$= (-1\ \text{MW}) * \left(\frac{\$43.88}{\text{kW}}\right)\left(\frac{1000\ \text{kW}}{\text{MW}}\right) = \$43{,}880$$

$$\text{Avoided T\&D}_{2016} = \text{load reduction} * \text{marginal cost}_{2016}$$

$$= (-1\ \text{MW}) * \left(\frac{\$82.90}{\text{kW}}\right)\left(\frac{1000\ \text{kW}}{\text{MW}}\right) = \$82{,}900$$

The lifetime Avoided T&D Infrastructure of the battery can then be determined by finding the Net Present Value of the value streams.

Table 2: Illustrative Example of the Avoided T&D Infrastructure Calculation

Year	Marginal Cost	Avoided T&D
2015	$ 43.88	$ 43,880
2016	$ 82.90	$ 82,900
2017	$ 49.68	$ 49,680
2018	$ 127.30	$ 127,300
2019	$ 119.43	$ 119,430
Discount Rate		5%
NPV		**$ 358,205**

Avoided O&M Costs

Although the Con Edison marginal cost study, referred to above, include operation and maintenance (O&M) expenses associated with marginal T&D investments, as well as an allocation of administrative and common costs, the methodologies used to develop O&M and administrative and overhead factors may not have been sufficiently forward looking and granular to reasonably reflect the full potential value that could be obtained from the distributed opportunities envisioned to address system constraints (see the testimony of Joel A. Andruski in Case 14-E-0493). Certain projects could result in lower operation and maintenance costs, due to, for example, lower equipment failure rates, while other measures may increase operation and maintenance expenses due to, for example, increased DER interconnections. These changes in O&M should be determined by using the utility's activity-based costing system or work management system. As an example, the impact of a particular measure could be determined by estimating the percentage of a field crew's time on a particular activity before the installed project and then estimating the time saved by the field service personnel after the project is installed. With the respect to the allocation of joint and common costs, some economists have suggested that these allocations should be performed in light of the relative price elasticities associated with changes in the demand for the various services which the Company provides. However, there is no widely accepted guidance on the most reasonable method for allocating common costs.

The method for valuing Avoided O&M Cost benefits specific to each utility should be included in individual utility DSIPs and Handbooks. We invite parties to comment on these issues.

Avoided Distribution Losses

The difference in the amount of electricity measured coming into a utility's system from the NYISO or distributed generators and the amount measured by the Company's revenue meters at customer locations is defined as the "Loss" or "Losses" experienced on the Utility's system. Losses can be categorized as technical and non-technical losses, where technical losses are the amount of energy lost on the utility's system as heat and the magnetic energy required to energize various pieces of equipment used by the utility, and non-technical losses represent energy that is delivered but not registered by utility revenue meters. For the purposes of these analyses, we will focus on technical losses.

Technical losses can be further categorized into fixed and variable losses, and attributed to various pieces of equipment. Fixed losses take the form of heat and noise and are attributable to individual pieces of equipment, such as cables and transformers, and do not change with increasing or decreasing current. Fixed losses are generally a property of the equipment, and cannot be reduced except by replacing such equipment with lower-loss units, or simply removing such units from service. Variable losses are generally due to electric energy being converted to heat at a rate proportional to the square of the current running through the piece of equipment, or I^2R losses. I^2R losses are lower when less electricity is being delivered, and greater when more electricity is being delivered. I^2R losses to deliver the same amount of power are lower at high voltage, and higher at low voltage. While both fixed and variable losses are significant, actions taken by customers and the utility will have a greater impact on variable losses since fixed losses can only be reduced marginally by replacing equipment with lower-loss models or removing equipment from service. Therefore we will focus on estimating the value of reducing variable losses. Table 3, below, shows illustrative examples of the relative magnitude of several different categories of losses in the Consolidated Edison Company of New York, Inc. (Con Edison) service territory. Utilities should file similar line loss data with their DSIPs and summarize them in their BCA Handbooks.

Table 3: Line loss as a percentage of energy delivered on various system components in Con Edison's 2007 Electric System Losses study

Portion of T&D Delivery System	Voltage Segment	Loss Type	
		Fixed	Variable
Transmission	500 kV	0.00%	0.00%
	345 kV	0.32%	0.52%
	138 kV	0.34%	0.50%
	69 kV	0.03%	0.05%
	TOTAL	**0.69%**	**1.07%**
Distribution	Primary	0.02%	1.12%
	Secondary	0.00%	1.56%
	Metering	0.18%	0.00%
	Equipment	0.78%	0.39%
	TOTAL	**0.98%**	**3.07%**
Unaccounted For		0.00%	0.65%
TOTAL		**1.67%**	**4.79%**

Variable losses should be considered when a project increases or decreases the load served on a utility's system. The impact of the increased or decreased load should be considered for all levels which will be affected. For example, a self-supplying microgrid connected at a utility's transmission voltage would reduce transmission line losses, but not distribution line losses. Similarly, an energy efficiency project at a residential customer location would result in decreased line losses from the utility's secondary system all the way through its transmission system. In the same way, increased line losses should be considered for projects which ultimately increase the load on the utility system. Projects which shift energy usage from one time to another also have an effect on losses, since variable losses are proportional to square of the current travelling through a line. That is, the avoided losses from reduced usage during on-peak times are greater than the incremental losses caused by increased usage during off-peak times. Time varying loss impacts should be considered if ample data exists to quantify them, but these effects may be comparatively small in magnitude. Finally, if a project materially increases or decreases the need for system reinforcement, fixed losses related to the equipment which is to be placed into or taken out of service should also be considered.

Staff proposes that in order to be consistent in their application, loss factors should be applied to the prices of the avoided cost components based on the loss characteristics of the utility system on which the load addition or load is connected. System loss characteristics are vitally important to the calculation of these data, so the latest system loss studies available should be used to determine the percentage of system losses. If such data is not available, efforts should be made to engage in a loss study, or otherwise to use the most applicable data available from other utilities. First, a loss percentage, or the ratio of the amount of energy lost on the utility system divided by the total electric sendout, must be determined. The loss percentage is equal to the sum of each applicable loss category (fixed or variable losses, for example). The loss percentage is then applied to adjust the price of the avoided cost component being calculated. For example, the prices associated with Avoided Energy, Avoided Generation Capacity, Avoided Externalities (specifically Approach 2 and 3 proposed below), and Avoided Transmission and Distribution Capacity Infrastructure. We invite parties to comment on this approach to apply the loss factor to the avoided cost components. In addition, again building on our desire for the BCA methodology to become more granular over time, we invite comment on the possibilities and limitations of how granular and dynamic the loss factor calculation can become at the distribution level (recognizing that increasing or decreasing the mix of DER resources can impact the underlying losses on the system).

EXAMPLE: Energy Efficiency

> A customer connected to the Con Edison secondary system installs energy-efficient equipment to reduce their total energy usage by an average of 1 kW per hour. The total annual kWh savings of the project would be approximately 8760 kWh. What would the associated reduction in line loss be, and what is its value?
>
> We assume that the customer's energy efficiency is not enough to eliminate the need for transformers or other infrastructure, therefore there are no fixed losses reduced by this program. Since the customer is connected to the secondary system, the energy usage reduction at the customer's location does reduce load on all higher levels of the distribution system and transmission system, therefore variable load reductions on the secondary distribution, primary distribution, distribution equipment, and all transmission voltages should be considered: in this example, the loss percentage is 4.14%. This loss factor would then be applied to adjust the prices applicable to all of the associated avoided costs such as, avoided energy, avoided generation capacity, and any others that apply. For

example, the avoided energy associated with this measure would be calculated as follows:

Since the customer is in the Con Edison service territory, we can use the NYISO Zone J average LBMP to determine the avoided energy. We will use the 2013 average Zone J LBMP of $0.052/kWh.

$$\begin{aligned}\text{Avoided Energy Value} &= \text{Energy impact} * \text{LBMP} * \text{Loss Percentage} \\ &= (-8760\ \text{kWh}) * \$0.052 * 4.14\% = \$-18.86\end{aligned}$$

More granularly, or dynamically, the hourly marginal price at the relevant level of the system could be grossed up by the marginal loss % avoided for that hour, at that level of the system.

Net Avoided Restoration Costs

Projects such as automated feeder switching or improved diagnosis and notification of equipment conditions could result in reduced restoration times. To calculate this avoided cost, utilities could compare the number of outages and the speed and costs of restoration before and after the project is implemented. Such tracking would need to include the cause of each outage. The change in the restoration costs could then be determined. We note that minimization of restoration costs often factors into a utility's decisions to invest in T&D infrastructure, so some portion of restoration costs are already included in the Avoided T&D Infrastructure category described above. Net Avoided Restoration Cost benefits specific to each utility should be included in individual utility DSIPs and Handbooks.

Net Avoided Outage Costs

Avoided outage costs could be determined by first determining how a project impacts the number and length of customer outages then multiplying that expected change by an estimated cost of an outage. The estimated cost of an outage will need to be determined by customer class and geographic region. We note that outage mitigation often factors into a utility's decisions to invest in T&D infrastructure, so some portion of outage costs are already included in the Avoided T&D Infrastructure category described above. Net Avoided Outage Cost benefits specific to each utility should be included in individual utility DSIPs and Handbooks.

Externalities

As noted above, in addition to pecuniary costs and benefits, utilities need to consider out-of-market public costs and benefits that DER impose or provide. Many of these (such as land, water, and neighborhood impacts) will depend on the specific alternatives considered and will likely need to be weighed in a qualitative and judgmental way. However, the quantitative impact of three damaging gas emissions—SO_2, NO_x, and CO_2—are measured and modeled at the bulk level and can be estimated at the DER level. Before discussing alternative ways to value these quantities, it is helpful to quickly review the traditional economic approach to analyzing the impact of this particular market failure.

A simple definition of an externality is "an effect of one economic agent on another that is not taken into account by normal market behavior."[14] The "normal market behavior" relevant here is that producers pay for the inputs they use in producing an output, such as MWh of electricity, and consider those costs when they decide whether to invest in a business or plant, how much output to produce, and what price they would need to receive to invest in that business or plant and to produce a particular level of output. However, when some of those inputs are public "goods" for which little or nothing is paid by the producers and consumers of the output, such as air or water that is free from pollution or a climate that is relatively stable, then too much of the public good is consumed. Greater levels of pollution, or climate change, are created than would occur if the public were appropriately compensated for the public input that is being consumed.[15]

In reality, public goods usually are not priced at the marginal cost that their use causes, sometimes called "marginal damage costs." Because their price is below the marginal damage cost, and often even at zero, governments create laws, rules, regulations, penalties, and fines to limit the quantity of the public good that is consumed,

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[14] Nicholson, Walter, Microeconomic Theory. (Hinsdale, Illinois: The Dryden Press, 1978), p.681.

[15] Consider what would happen if fossil fuels were all owned by the government and given away for free: the cost of producing electricity would be much lower, at least initially; significantly greater quantities would be produced and consumed; this, in turn, would exhaust the entire stock of fossil fuels in a very short amount of time. Prices for electricity would then skyrocket. Fortunately, fossil fuels are not given away for free. They are, generally, priced at the pecuniary, though not social, marginal cost it takes to provide them, or, at times when supply-side market power is successfully exercised, somewhat above marginal cost.

limiting the harm done by overuse. It is rarely, if ever, known whether such "command and control" approaches lead to an economically efficient limitation on the quantity of public goods used. Many economists have argued for years for externality prices[16] to be set at estimated marginal damage costs for each unit produced of various pollutants, in particular SO_2, NO_x, and, recently, CO_2. For a number of reasons, cap and trade (C&T) programs have been implemented to try to achieve similar results.[17] Other public requirements such as environmental permitting or restrictions can result in a degree of social cost internalization.[18]

Both externality "taxes" and C&T programs result in a price being placed on each ton of damaging gas emitted, so both approaches "internalize" some or all of the external damage costs. This is important to keep in mind when valuing the net, or un-monetized, portion of marginal damage costs caused by bulk power generation. If externality prices were set high enough to equal marginal damage costs per ton emitted, wholesale LBMPs would fully reflect the social value of emission-free generation with respect to the pollutants covered by the emission pricing program.[19]

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[16] Often called "taxes," but they differ from typical taxes in that the rationale for this charge is to improve market efficiency by pricing an otherwise un-priced, or under-priced, public good. Most ad valorem taxes act in the opposite way, somewhat distorting market efficiencies as a necessary device to collect a required revenue amount. Thus, "CO_2 price" is economically more accurate than "CO_2 tax."

[17] Externality "taxes" place a price on each unit of external damage created, for example a $/ton charge for each ton of damaging gas emitted. A C&T plan sets a quantity limit, for example total tons of emissions per year, and producers bid a $/ton price for their share of that limit. Thus, the main difference is that the "tax" approach sets a firm price, and quantities emitted vary depending on the price, whereas C&P programs set a firm quantity and the $/ton price varies according to the year's quantity cap and producers demand for allowances to emit under that cap. We refer to both of these, generally, as "emission pricing programs."

[18] While such requirements certainly impose costs to attain socially desirable outcomes, it can be a complicated matter to calculate whether, and the amount by which, they increase marginal production costs in a way that provides efficient price signals to mimic or offset net marginal emission damage costs. Emission pricing programs attempt to take on this issue directly.

[19] As the New York Department of Environmental Conservation noted in its comments on microgrids (Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV) and Notice Soliciting Comments on Microgrids, the Department of Environmental Conservation's Office of Air Resources, Climate Change and Energy, Office of Environmental Justice, and Office of General Counsel, May 1, 2015), it is important to consider the precise, and sometimes differing, policies that affect both large central generation and smaller, distributed generation. The C&T programs only apply to generators of 25 MW capacity or larger. Smaller fossil generators do not pay for any allowances that internalize some wholesale emission damages. Any emissions from such generators should not be credited with any "internalized" cost avoidance at the wholesale level, and would impose total marginal damage costs per unit emitted compared to an emission-free source.

This conceptual economic construct provides a basis for considering alternative approaches to value the social benefits and costs of alternative DER choices attributable to greenhouse gases and other air pollutants. In recognition of the wide range of possible approaches and the numerous and serious implications associated with each approach, this White Paper does not make a specific recommendation in advance of comments from interested parties. The following three approaches are presented for comment. Parties are encouraged to suggest other approaches they may consider better suited for inclusion as part of the BCA analysis.

In evaluating the three general approaches, it is useful to distinguish between the validity of each method for quantifying the value of externalities and the challenges relating to the application of each method. For example, a marginal damage cost approach (such as Approach #2) may provide the most complete, rational and defensible approach for valuing the damage attributable to emissions of carbon dioxide and other pollutants, while other approaches may prove to be easier to implement. Approaches #1 and #3 build off of existing policy mechanisms (market-based emission trading or renewable energy incentives, respectively).

Approach #1: Rely on Values Reflected in LBMPs. As noted, C&T programs have been used to "internalize" some social costs into wholesale LBMPs. SO_2 and NO_x trading have a volatile 20 year history.[20] After many legal delays, the reinstatement of the Cross State Air Pollution Rule[21] (CSAPR) is once again resulting in above-zero prices for NO_x and SO_2.[22] Meanwhile, prices for CO_2 emission permits in the Regional Greenhouse Gas Initiative (RGGI) have slowly increased in the almost seven years since the program began.[23]

Staff's proposed use of NYISO's CARIS 20-year LBMP forecasts to reflect avoidable energy costs at the bulk level is discussed earlier in this White Paper. In

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[20] For example, see Schmalensee, Richard and Robert N. Stavins, "The SO_2 Allowance Trading System: The Ironic History of a Grand Policy Experiment," Journal of Economic Perspectives, Vol. 27, No. 1, Winter 2013, pp. 103-122.

[21] Available at http://www.epa.gov/airtransport/CSAPR/.

[22] Available at http://www.evomarkets.com/pdf_documents/evo/csapr_market_update_apr_2015.pdf.

[23] The most recent CO_2 permit auction (3/11/2015) cleared at $5.41. Earlier results are shown at http://www.rggi.org/market/co2_auctions/results.

producing these forecasts, the NYISO assumes a trajectory of $/ton emitted compliance costs for each of the three damaging gasses discussed. This forecast is modified in each CARIS update. The latest estimates used in the 2014 CARIS 2 forecasts are shown in Table 4.

Table 4 shows that the 2014 CARIS 2 LBMP forecasts already reflect some compensation for the social damage caused by each of these gasses. If the CARIS LBMP estimates are used to value emission-free DER in a REV BCA analysis, these resources are being credited with the emission values in Table 4. Under Approach #1, that is the total value that would be attributed to emission-free DER resources for the DSIP BCA when these are compared to bulk system resources. Arguably, because the C&T programs that these estimates reflect are not applied to generators smaller than 25 MWs, any smaller distributed generator (DG) that does emit these gasses should not receive these credits. Under this approach, any smaller DG that emits these gasses should have its pecuniary costs increased by the values in Table 4 (or the relevant version in future CARIS updates) when they are compared to emission-free DER or bulk power.[24]

The benefits of such an approach are its simplicity and its balanced, broad-based application. The strength of such emission pricing programs is that society is imposing consistent costs on a large portion of the relevant economic decision-makers and allowing them to find ways to efficiently respond to these broadly applied price signals. In the case of the RGGI program, the RGGI States have banded together and agreed to allow a common auction mechanism to set the CO_2 permit price they will all accept, reducing the perverse economic incentives and interstate competitive impacts that would result from each using a different value.

The main detriment of such an approach is that the values reflected in the CARIS estimates in Table 4 were never intended to be an estimate of the full marginal damage costs. These represent the NYISO's best estimate of the compliance prices that would be produced by these mitigation programs.

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[24] To the extent that emitting DGs are more efficient than bulk generators, this will be reflected in the comparison of their pecuniary costs to the aggregation of the described benefits, including avoided LBMPs. The addition of Table 4 CARIS compliance costs to the emitting DG's pecuniary costs simply adjusts for an inappropriate credit that these DG resources otherwise would get since they do not have to purchase the allowances assumed in the LBMP forecasts.

Table 4. Allowance Price Forecasts Assumed for 2014 CARIS LBMP Estimates (Nominal $/Ton)

Table 4. Allowance Price Forecasts Assumed for 2014 CARIS LBMP Estimates (Nominal $/Ton)								
	SO2	NOx	CO2			SO2	NOx	CO2
2012	$2.50	$64	$2.08		2024	$2,076	$146	$17.13
2013	$3.19	$82	$2.09		2025	$2,172	$152	$18.05
2014	$3.44	$88	$3.98		2026	$2,267	$160	$19.06
2015	$3.68	$95	$5.75		2027	$2,362	$168	$20.11
2016	$1,316	$101	$7.72		2028	$2,457	$172	$21.26
2017	$1,411	$104	$9.70		2029	$2,552	$174	$22.46
2018	$1,506	$109	$10.06		2030	$2,647	$180	$23.72
2019	$1,601	$114	$10.37		2031	$2,742	$189	$25.07
2020	$1,696	$118	$13.63		2032	$2,837	$200	$26.49
2021	$1,791	$125	$14.40		2033	$2,933	$211	$28.10
2022	$1,886	$134	$15.33		2034	$3,028	$222	$29.93
2023	$1,981	$140	$16.23		2035	$3,123	$232	$31.95

<u>Approach #2: Detailed Calculation of Net Marginal Damage Costs</u>. It is possible to use the CARIS model and database to calculate the change in the tons produced of each gas by the bulk system when system load levels are reduced. If we assume that this quantity of gas reductions would occur if DER "backed down" system load levels,[25] then those quantity estimates could be multiplied by an estimate of the $/ton value of marginal damage costs, net of the costs already internalized by CARIS. These would yield a $/MWh estimate of the adder emission-free DER should receive in addition to the CARIS LBMP when comparing emission-free DER to bulk energy sources. Equivalently, in the DSIP planning BCA, the cost of the bulk power could be raised by this net $/MWh adder when the emission-free DER's costs are compared to the alternative of purchasing bulk energy. In this approach, when comparing DER that emits quantities of these gasses to emission-free DER, or to bulk level energy, the full marginal damage cost estimates, not net of the CARIS compliance estimates in Table 4,

[25] Unfortunately, as we will discuss below, this assumption does not hold very well under a C&T compliance regime for these gasses. However, it is very useful to go through this exercise to inform the decision-making at hand.

should be added to the emitting DER's pecuniary costs per MWh. Appendix C describes in detail Staff's use of the United State Environmental Protection Agency (EPA) damage cost estimates and the CARIS database to estimate net marginal damage costs.

A benefit of this approach is that it seeks to directly address the marginal damage costs caused by certain externalities. The method is largely transparent and repeatable by others.[26] Sources and assumptions can be reviewed and disputed.

However, this approach has a number of shortcomings. First, the marginal damage cost estimates are quite non-robust. An extremely small change in SO_2 and NO_x emission levels in the General Electric's Multi-Area Production Simulation Model (MAPS) run of the CARIS database yields large $/MWh impacts. This is due to EPA's extremely large estimates of mortality costs per ton of emission. While the EPA estimates may be defensible, it is unclear whether such small changes in MAPS are accurate enough to be relied on for such large impacts in the value of energy. Further, the SO_2 and NO_x quantities in MAPS are very dependent on the assumed future existence of coal plants in the electric power markets administered by PJM Interconnection, LLC. There are many factors that could reduce the number of these plants from the levels assumed in CARIS, lowering the already small SO_2 and NO_x changes.

For these reasons, under this approach, one option, for party comments, is to add no additional social value for SO_2 and NO_x to the compliance forecasts already reflected in the CARIS LBMPs (i.e. use Approach #1 for these two emissions). However, when comparing emission-free DER to emitting DER, none of these modeling uncertainties apply. Presumably, when comparing one DER alternative or portfolio to another, the specific resources being compared will be known. Full damage costs of the SO_2 and NO_x emissions should be reflected for the emitting DER under this approach, especially in densely populated centers such as New York City. Parties

[26] One exception to this is the CARIS database itself. Because it contains market sensitive information on plant operating characteristics, only the NYISO and DPS Staff are allowed to use and investigate the details of the database. The important assumptions used in CARIS are presented to, and vetted with, all the stakeholders at the NYISO. However, only aggregated outputs, such as annual LBMP or emission levels, can be presented to the public.

should comment on whether the EPA $/ton damage cost estimates are the appropriate level for this purpose, or if alternative estimates should be used and, if so, why.[27]

Another drawback of this approach is the wide range of estimates that exist for the $/ton damage caused by CO_2 induced climate change. The appendix tables show that the EPA estimates for CO_2 damage costs differ dramatically depending on the discount rate used. Usually, for net present value calculations, the discount rate is based on the opportunity cost of capital (for our utilities, this is at least 5%, in real terms). This would lead to CO_2 prices approximately equal to the levels already assumed in the CARIS LBMP estimates, resulting in a zero adder. However, some economists, led by Nicholas Stern, have argued that such discount rates are "unethical" when applied to issues such as climate change. Other economists, such as William Nordhaus, refer to Lord Stern's approach as a "prescriptive" discount rate, and argue for the more traditional "descriptive" discount rate based on the opportunity cost of capital, since it should reflect the value of alternative values of investment dollars.[28] The central case recommended by the U.S. Interagency Working Group is 3%. However, the issue is far from settled, especially when applied to the specific case of valuing CO_2 damages over a long timeframe.[29]

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27 To inform future refinement of this process, NYSERDA plans to conduct a study that would estimate and project externality values (including health and other effects) for all energy types (including electricity generation) on a regional basis in New York State.

28 ". . . [T]he descriptive analysis holds that the discount rate should depend primarily on the actual returns that societies can get on alternative investments. Countries have a range of possible investments: homes, education, preventative health care, carbon reduction, and investing abroad. Particularly in a period of tight government budgets and financial constraints, the yields on such investments might be very high. In such a context, the prescriptive approach of a very low ethical discount rate just does not make any economic sense…According to the descriptive view, the discount rate should be primarily determined by the opportunity cost of capital, which is determined by the rate of return on alternative investments." Nordhaus, William, *The Climate Casino: Risk, Uncertainty, and Economics for a Warming World*. New Haven: Yale University Press, 2013, p. 187.

29 As the EPA Social Cost of Carbon (SCC) documents (http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf) note: "the literature shows that the SCC is highly sensitive to the discount rate" and "no consensus exists on the appropriate rate to use for analyses spanning multiple generations". One interesting paper, led by Kenneth Arrow (http://www.rff.org/RFF/Documents/RFF-DP-12-53.pdf), explores alternative approaches such as a declining discount rate, where "the impact of possible catastrophes could also have a significant impact on the discount rate." Nordhaus also acknowledges the open question of declining discount rates over time (p.350), and risk premiums for climate hazards due to modeling difficulty (pp. 141-3), both which would tend to increase the estimate of damage costs. The EPA also sponsored a workshop with Resources for the Future on this issue, described at http://www.rff.org/Publications/Resources/Pages/183-Benefits-and-Costs-in-Intergenerational-Context.aspx

Nonetheless, even if one agrees with Professor Nordhaus on discount rates, he points to the wide range of estimates coming from alternative models, prices per ton that range from $10 to $50 in 2020, and from $20 to $85 in 2030, with the gap widening exponentially as one goes out in time.[30] As further evidence of the wide range of uncertainty, the World Bank compiled a summary of carbon prices being used throughout the world.[31] The prices range from $2 per ton in Japan, to $168 per ton in Sweden. It should be noted that these represent a wide range of policy responses to the climate change concern, and do not necessarily represent any entity's estimate of full marginal damage costs.

Yet another drawback of this approach is that it assumes that reducing the load requirement level that the bulk system serves actually will reduce the emissions associated with that load level; that is, that the marginal emission reduction modeled in MAPS actually will occur. However, because emission prices are set via C&T programs—rather than a fixed emissions price per ton—this assumption is technically incorrect. C&T programs set a cap for a given year and sell allowances to meet that cap, regardless of what the bulk load level decreases to. The net effect is not to reduce emission quantities, but to shift the demand for allowances down, reducing the allowance price. In other words, C&T programs act like a vertical supply curve and reductions in bulk demand levels simply move the allowance price down that fixed supply level. A graphical illustration of the RGGI C&T program is shown in Figure 1 below.

While the RGGI C&T program is mostly a vertical supply curve, there are two flat portions. At the lower bound, if the cap were completely non-binding, then the floor acts like a fixed price and reductions in load will lead to reductions in CO_2 emitted (horizontal movements as lower demand curves intersect the flat floor price). Similarly, the Cost Containment Reserve (CCR) acts like a fixed-price pressure valve.[32] The CCR is a set-aside of a fixed quantity of additional allowances per year, part or all of which is added to a quarterly auction's supply if prices rise to the given year's trigger price. If the RGGI

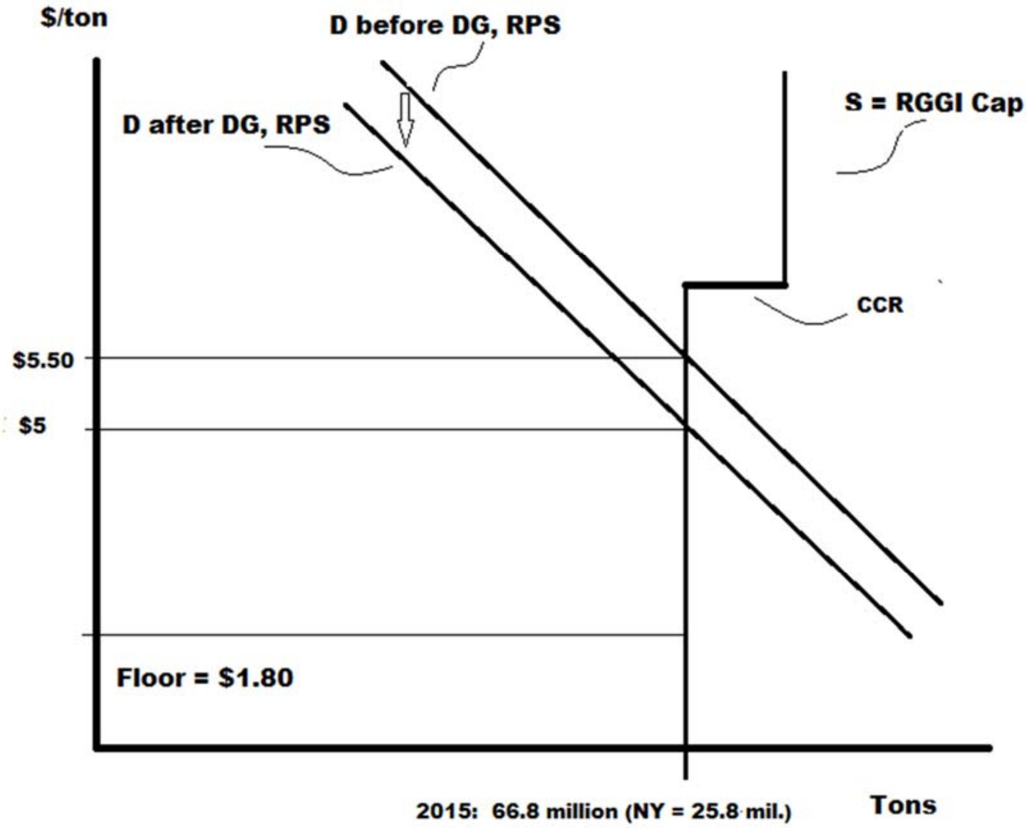
[30] Nordhaus, p. 228.

[31] http://www.worldbank.org/content/dam/Worldbank/document/SDN/background-note_carbon-tax.pdf.

[32] For 2015, the CCR trigger price is set at $6 per ton. It rises to $8 per ton in 2016, $10 per ton in 2017 and increases 2.5% per year thereafter.

price rises to the CCR level, a maximum of up to 10 million allowances will be added to the cap to keep prices from rising, at least until the 10 million allowances are used up. If the demand for allowances happens to clear in that range in a given year, then a decrease in bulk requirements will reduce the CO_2 emitted. As long as demand stays within the flat portion of the supply curve, it acts like a fixed emission price per ton. However, for the most part, C&T programs allow the price to adjust, not the quantity of emissions.

Figure 1. Effect of Reducing Bulk Requirements on Bulk CO_2 Emissions



Where,

D =	Demand curve for allowances reflecting generators' willingness to pay
DG, RPS =	Distributed generation and Renewable Portfolio Standards, resources and programs that lower bulk revenue requirements to be served by fossil units and, thus, the fossil units' willingness to pay for allowances
S =	Supply curve for RGGI allowances, set by cap levels and certain exceptions
$/ton =	Clearing price for RGGI allowances for a given auction (4 per year)
Tons =	Tons of allowances sold in a given auction
Floor =	Minimum price that allowances will be sold for
CCR =	Cost containment reserve, trigger price at which a fixed number of additional allowances are added to an auction to restrict price increases (currently, 10 million allowances are allocated to the CCR each year)

This by no means leads to a conclusion that emission-free and reduced-emission DERs have no externality value in a C&T context. Reductions in bulk demand will lead to reductions in the C&T price. This, in turn, will allow lowering of the caps if prices are the target and concern of policymakers. Further, developing emission-reducing DER markets provides other benefits, such as clean energy market development, fuel diversity and the related future hedge "optionality" provided relative to the addition of one more gas plant. Thus, emission-free DER does provide external value over emitting DER, and over bulk energy. However, what that value is, per MWh, is actually more difficult to calculate and more nuanced than assumed in this approach.

One final drawback of Approach #2 is that it provides a special "adder" to small emission-free generation independent of what is provided to large emission-free generation. If small and large emission-free generators are receiving different compensation for providing the same external values to society, this can lead to "perverse incentives." Essentially, perverse incentives are ones that provide an advantage to one alternative, even if another alternative provides the same value at a lower cost, or a greater value at the same cost. If the C&T prices or an alternative emission price were used as the sole social valuation for all resources, and these were set to reflect the full value of emission damages, then all resources would get balanced incentives and perverse incentives would be avoided. However, emission pricing programs seem to set prices below marginal damage costs. Furthermore, they are not the only program for compensating large scale renewable (LSR) resources for the external values that they provide.

Approach #3: Large Scale Renewable Parity. In addition to the RGGI C&T program, the other significant program that New York has for compensating renewable (most of it emission-free) bulk generators for the external costs they avoid, that is, the social value that they provide, is the Renewable Portfolio Standard Main Tier (RPS-MT) solicitation program. Since 2004, NYSERDA has conducted nine large-scale renewable solicitations, which provide contracts for above-market payments to renewable generators. Over the years, many factors have affected the level of the above-market payments to eligible generators, including the price of natural gas. This is because the NYSERDA contracts only pay the above-market portion of qualifying generators revenues, by purchasing only Renewable Energy Credits (RECs) from generators and leaving them to sell energy, capacity, and any other products into the wholesale market. Their remaining revenues come from electricity sales to the NYISO, or to other buyers.

The REC prices bid in each solicitation reflect each generator's forecast of future LBMPs, including whatever level of internalized emission compliance costs they foresee. Thus, the REC prices paid, based on the bids accepted, reflect the State's willingness to pay for the additional social values that these renewable resources provide, over and above the C&T values that are internalized in the wholesale LBMPs. It should be noted that these social values represent more than just avoided emission damages,[33] including fuel diversity.

Since the shale-gas-led structural change in natural gas prices in 2008, NYSERDA has conducted 6 RPS-MT solicitations, five for REC contracts of 10 year terms, and one for contracts with variable terms, up to 20 years. The simple average of the REC prices posted by NYSERDA for these solicitations is $24.93, or approximately $25 per MWh. While there are many cost-causative reasons for differing REC prices over the years, including the extension of contract terms,[34] it is nonetheless true that this $25/MWh figure represents NY's average willingness to pay in recent years for all of the social benefits provided by LSRs.

One simple approach to valuing emission-free, or renewable, DER in the first round of utility DSIP planning and implementation BCAs is to raise forecasted CARIS LBMPs by $25 per MWh when comparing grid-level solutions to emissions-free, or renewable, DER.[35] This would provide an explicit link between LSR incentives and small-scale emission-free or renewable incentives. For future DSIPs, under this approach, the "parity" above-market value should be recalculated to reflect recent developments in LSR programs. The number of years one averages LSR REC payments will determine how stable or dynamic this parity value is: a rolling five or six year average would provide a fairly stable adder, while a value that reflects the most recent year's value, or a 2 or 3 year average, would be more volatile and reflect more

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[33] At the time of the 2004 RPS Order, the NY Public Service Commission listed the social benefits as "ancillary benefits such as increased fuel diversity and energy security, the potential for economic development as a result of growing industries that typically tap into indigenous resources and invest in local and regional economies, and reduced environmental impacts."

[34] This was a response, in part, to the trend of increasing REC prices, thus reflecting the state's willingness to pay.

[35] As discussed above, behind-the-meter resources should be credited with avoided losses. This also applies to externality payments. Thus, under this approach, the $25 parity value should be increased to reflect to the extra bulk level externalities that are avoided because losses are avoided.

up-to-date values. Such an approach would be self-adjusting to maintain parity with whatever preference the state reveals in paying LSRs. Parties should comment on what method, if any, should be used to adjust such a number to reflect differences in length of contract term.

To maintain simplicity, emitting (or non-renewable) DERs could be treated similarly; that is, the same $25 per MWh figure could be applied to their pecuniary costs when comparing to emission-free or renewable DER. But this would ignore the differences among emitting DER, for example, the different impacts of a combined heat and power generation as compared to diesel generation). It further ignores that DGs smaller than 25 MWs do not purchase C&T allowances, and so should not get the full credit of the CARIS LBMPs. Hence, under this approach, each emitting DER should have its pecuniary costs increased by the $25 per MWh "parity value" plus the relevant $/ton compliance cost charges reflected in the CARIS estimates (i.e. the Table 4 values, as updated) when DER is valued in the DSIP BCAs.

Since this approach relies on above-market payments to bulk renewable generators, and since not all qualifying "renewable" generators are strictly "non-emitting" generators, parties should comment on whether this approach should treat "renewable" DG differently than "non-emitting" DG.

Net Non-Energy Benefits

Non-energy benefits include, but are not necessarily limited to, such things as health impacts, employee productivity, property values, reduction of the effects of termination of service and avoidance of uncollectible bills for utilities. While Staff recognizes the existence of these costs and/or benefits, we propose that such difficult-to-quantify costs and benefits not be monetized at this time. However, when utilities consider specific alternatives, they should recognize any of these impacts when relevant, and weigh their impacts, quantitatively, when possible, and qualitatively, when not. For example, if a DER proposal for low and moderate income customers results in a reduction in the number of utility service terminations, the corresponding resource savings should be reflected in the SCT cost test results. Similarly, if the same proposal also reduced uncollectible bills, the corresponding transfer payment would be reflected in the RIM cost test results. We invite comment from parties on what other non-energy benefits should be considered and possible methods for quantification.

Valuing Costs

Program Administration Costs

Some projects undertaken will be more complicated than operating distributed generation and will require program administration performed and funded by utilities or other parties. The cost to administer and measure the effect of such programs should be included in the determination of the program's cost effectiveness.

Added Ancillary Services Costs

Required ancillary services, including spinning reserve and frequency regulation, could be increased with greater penetration of intermittent renewable resources such as wind and solar power. Such projects will require the grid operator to establish a higher level of ancillary services or to purchase additional ancillary services from sources other than conventional generators. While this cost may be difficult to forecast because ancillary services vary significantly from year to year and are market-based, Staff requests that parties comment on how such a forecast could be done.

Incremental T&D and DSP Costs

Incremental T&D costs borne by the utility or DSP should be considered to the extent that the characteristics of a project cause additional costs to be incurred. A project might cause such costs to be incurred by using energy or demand during peak hours and contributing to the utility's need to build additional infrastructure. Conversely, a shift of a large enough portion of load to off-peak hours might prevent transformers and other power equipment from experiencing the designed cool-down period necessary to maintain reliable operation of the equipment, resulting in a need for reinforcement. Any additional T&D infrastructure costs caused should be considered and monetized in a similar manner to the method described in the Avoided T&D Infrastructure Costs section above.

Participant DER Costs

The equipment and participation costs assumed by DER providers should be considered when evaluating the societal costs of a project or program. For example, a participant in a bring-your-own-thermostat direct load control program assumes two costs: (1) the cost of the controllable thermostat; and (2) the cost of decreased comfort when the participant's air conditioning equipment is cycled off during a demand response event. While a participant's equipment costs should be relatively simple to monetize, comfort and other opportunity costs are much less apparent. Previous studies and programs have assumed that, in general, participant opportunity costs are approximately 75% of any incentives paid to participants.[36] Parties should comment on this simplifying approximation and recommend any preferred alternatives.

"Lost" Utility Revenues

Because of the presence of Revenue Decoupling Mechanisms (RDMs) at every electric utility in the State of New York, very little sales-related revenue is actually lost to the utility due to a decrease in electricity sales or demand. While the utility is made whole from the decrease of sales, the revenue which would have otherwise been recovered through the rates charged on those lost sales is instead recovered from other customers through the RDM, marginally increasing the costs of other electricity sales. The bill impacts on non-participating customers should be considered for the purposes of determining the ratepayer impact measure of a project or program.

Utility Shareholder Incentives

The Commission's Order Adopting Regulatory Policy Framework and Implementation Plan (Track One Order) allows utility companies to propose financial performance incentives on Demonstration Project expenditures. In addition, Track Two of the REV proceeding includes consideration of incentive ratemaking. Financial incentives tied to DER projects have also been previously approved by the Commission in its Order Establishing Brooklyn/Queens Demand Management Program in Con Edison's service territory. As the utilities in New York State begin to file plans for

[36] This approach has been employed by Con Edison in evaluating the cost-effectiveness of its Demand Response programs, and is detailed in the February 10, 2014 "Cost Effectiveness of CECONY Demand Response Programs Final Report

demonstration projects, such financial incentives are likely to become increasingly common. The costs to ratepayers of such incentives should be considered when determining the cost effectiveness of such projects and programs.

Net Non-Energy Costs

There may be a number of non-energy related costs which result from the various projects undertaken as part of the REV proceeding. These costs may include, but are not limited to, indoor air pollution and noise pollution resulting in siting of generators or other power equipment. A portion of these costs may be included in other cost categories and should not be monetized a second time. However if there are costs beyond those already included they should be considered here. Staff requests that parties comment on which costs should be included in this category and how such costs should be monetized.

Conclusion

In this White Paper, Staff proposed a general framework for evaluating the benefits and costs of alternative utility investments and procurements to address identified system needs. To that end, Staff looks forward to receiving comments on all aspects of the White Paper and specifically invites attention to the questions of what analytical components should be included in a BCA, the method for determining the value of the component, the frequency of updating such values, the process for, and contents of, utility specific “BCA Handbooks,” and the approach to applying the BCA in specific applications.

Appendix A: Proposed ICAP Spreadsheet Model

[See Accompanying Electronic Spreadsheet File]

Appendix B: Marginal Cost Studies

[See Accompanying PDF Document]

Appendix C: Technical Explanation of EPA-Based Marginal Damage Cost Calculation (Approach #2)

The air pollutants coming from fossil fuels used in generating electricity (coal, oil, natural gas) are primarily sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and carbon dioxide (CO_2). Approach #2 relies on methods developed by the U.S. Environmental Protection Administration (EPA) to focus on the human health damages of increased emissions of these pollutants to estimate the environmental cost of electricity generation.[37] For SO_2 and NO_x, we use EPA's estimated health co-damages from changes in fine particulate matter ($PM_{2.5}$). For CO_2 we use EPA's estimated social cost of carbon (SCC). Of the three approaches proposed in the White Paper, this is the only one that attempts to value the total damage costs.

Social Cost of CO_2

The SCC is an estimate of the monetized damages to global society associated with an incremental increase in carbon emissions in a given year. It is intended to include changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change, etc.

In 2008, a federal court ruled that agencies must adopt nonzero monetary values when considering the effects of carbon dioxide pollution.[38] In 2010, the Office of Management and Budget and Council of Economic Advisers established an interagency working group to determine a single metric for all federal agencies, referred to as the Social Cost of Carbon (SCC). The most recent update to the SCC was released in 2013. As stated, the intent of the SCC is to "allow agencies to incorporate the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses of regulatory actions"[39] The interagency workgroup and SCC were designed to incorporate

[37] Due to modeling limitations, we did not include the environmental cost of direct emissions of particulate matter ($PM_{2.5}$), ammonia (NH3), and volatile organic compounds (VOC). The emissions of these omitted pollutants are very small compared to the three primary pollutants we have considered.

[38] Reviewed in GAO REGULATORY IMPACT ANALYSIS: Development of Social Cost of Carbon Estimates GAO-14-663: Published: Jul 24, 2014. Publicly Released: Aug 25, 2014. Available at http://www.gao.gov/assets/670/665016.pdf

[39] 2013 Technical Support Document available at https://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.

multiple lines of evidence through interagency consensus. In 2014, the Government Accountability Office released an investigation into the interagency workgroup and 20103 SCC update and found that the process used to establish the SCC was robust.

To incorporate multiple lines of evidence, the SCC incorporates the outputs from 3 peer-reviewed economic models that employ different methodologies: DICE 2010 (Nordhaus), FUND 3.8 (Anthoff and Tol), and PAGE 2008 (Hope). By considering multiple models, the SCC represents a defensible approach to the uncertainties inherent to climate change and any other attempt to project into the future. However, as GAO and others have indicated, the SCC does not include all possible damages and is likely an underestimate of the true costs to society from climate change. Accordingly, the SCC values and underlying models are not static and will be regularly updated.

The SCC represents the net effect (damages and benefits) to society of a marginal increase in emissions and it is reported as a matrix representing model averages across different time periods and discount rates as well as a "4^{th} column" that reports the 95th percentile of all models, or the most severe damages. Emissions that occur further in the future are considered to have an increasingly severe impact, so the SCC increases with time. However, larger discount rates, e.g., 5%, reduce this value. For example, the latest EPA cost estimates for emissions occurring in 2020 (in constant 2011 dollars) are $13 per ton when discounted at a 5% rate, $46 per ton when discounted at a 3% rate (the "central value" of the SCC), $68 per ton when discounted at a 2.5% rate, and $137 per ton when looking at the 95^{th} percentile for all models, discounted at 3%.[40] The EPA Table is reproduced as Table C1.

Health Impacts of SO_2 and NO_x

Both SO_2 and NO_x are precursors for $PM_{2.5}$ formation and SO_2 and NO_x emissions would increase overall ambient concentrations of these pollutants as well as $PM_{2.5}$. Studies found that increasing exposure to $PM_{2.5}$ causes significant human health damages including premature mortality for adults and infants, cardiovascular morbidity such as heart attacks and hospital admissions, and respiratory morbidity such as asthma attacks, bronchitis, hospital and emergency room visits, work loss days, restricted activity days, and respiratory symptoms (EPA 2013a).

[40] Available at http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.

EPA analyzes the changes in the health incidence per year in response to changes in the ambient concentrations of $PM_{2.5}$, utilizing the concentration-response relationships obtained from the existing expert studies. EPA evaluates each incidence using either individual willingness to pay for a risk reduction, such as mortality, or the medical cost of a treatment, such as hospital admissions. The estimates provide the total monetized $PM_{2.5}$-related damages on human health of reducing one ton of SO_2 or NO_x emissions.

We use EPA's Co-Benefits Risk Assessment (COBRA) screening model to estimate the marginal cost in health effects of SO_2 or NO_x emissions. COBRA is a screening tool that provides preliminary estimates of the impact of air pollution emission changes on ambient $PM_{2.5}$ air pollution concentrations and translates this into monetized health effect impacts.

The COBRA model contains detailed emissions estimates for 17 U.S. sectors, including electricity generating units. The assumptions are for 2017 and contain a baseline ("business-as-usual") and a "control case" that reflects the current federal environmental regulations. The relationships between the changes in pollutant emissions and the changes in monetized health effects are determined by a range of health impact functions and economic values of adverse health incidence. A user can create his own new scenario by modifying the built-in control case and COBRA generates the change in the values of air pollution-related health impacts. Emission changes can be entered at the county, state, or national level (EPA 2013c).

For each pollutant, we run a scenario by specifying a reduction of a fixed amount of emissions from the COBRA control case for electricity generating units in NY. COBRA generates the resulting change in the value of air pollution-related health impacts. We then divide changed value of the health impact by the amount of emission change. The result is the per-ton value of the health effects of emission change, or marginal value of health impact of the pollutant emissions. This marginal cost approach should provide a relatively robust outcome, because it largely depends only on the built-in health impact functions and economic values of health incidence.

Since NY is affected by emissions from neighboring regions, we also estimate the health effect of SO_2 and NO_x emissions for the states in PJM Interconnections (PJM), ISO New England (NE), and Ontario. We do so also because the health effects of pollution emissions vary significantly geographically. The variability is significantly in some cases, depending on the state's generation portfolio as well as demographic and geographic characteristics. Researchers found that the health damage of an increase in $PM_{2.5}$ varies by the location of the emission reduction, the type of source emitting the precursor, and the specific precursor controlled (EPA 20013a).

COBRA provides high and low estimates at discount rates of 3 or 7 percent. The high and low estimates correspond to the larger and smaller effects that two studies estimated for changes in ambient $PM_{2.5}$ levels on adult mortality, non-fatal heart attacks, and total health effects. The discount rates are used to calculate the present value of future damages, as it is believed that damages lag $PM_{2.5}$ exposures. To be consistent with our choice of a discount rate of 5 percent for SCC, we run our scenarios at both 3 and 7 percent and use the average as a proxy value for each pollutant.[41] We decided to provide these costs for both 3 and 5 percent.

The results coming from COBRA is based on one-year baseline assumptions for 2017, we decided to use GDP price inflator to extrapolate our estimated health damage costs for SO_2 and NO_x to the rest of 2016-2035. There are several reasons we use this approach. First, the methodology we use is a "marginal analysis." We use the COBRA model to calculate the increment or decrement health benefits corresponding to incremental or decrement in a criteria pollutant. The result of such marginal studies will be less impacted by the change in the national generation portfolio. Modeling health damage costs for extended years accounting for all changes in the national generation portfolio and environmental regulations is beyond our capability. Second, more than 95 percent of the health damage cost embedded in the COBRA model is the cost of mortality, or statistical value of life (SVL). The SVL is correlated with personal income and it is reasonable to assume it would grow with general inflation.

[41] The estimates for PJM and NE are emission weighted averages for the states within the region. The U.S. average is used for Ontario. The inflation adjustment as specified in Footnote 3 is used to convert the estimate to nominal dollars.

Estimating the Total Cost per MWh

To apply marginal damage cost estimates in a resource portfolio BCA, the $/ton damage estimates must be converted to $/MWh estimates. That is, we must estimate the increased tons of each emission caused by a marginal increase in the MWh of electricity generated (or tons saved by a marginal reduction in MWh generated).

To estimate total cost of SO_2, NO_x, and CO_2 emissions on a per-MWh basis, we use General Electric's Multi-Area Production Simulation Model (MAPS) to estimate marginal rates of emissions. The MAPS model includes detailed load, generation, and transmission representation for NY and neighboring areas and simulates electric energy production costs and associated SO_2, NO_x, and CO_2 emissions while recognizing transmission constraints and import limits.

The MAPS model input we used were developed by the New York Independent System Operator (NYISO) and contains base case assumptions for load, energy requirements, capacity, and emission rates in NY as well as in PJM, NE, Ontario for 2016-2035 (2014 CARIS).[42] We run an alternative scenario by change load and energy requirements in NY by 1 percent from the base case. We then calculate the changes in emissions in tons by region, or the differences in the MAPS outcome between the alternative scenario and the base case assumptions divided by the increase in the energy requirements in NY.

To get the gross damage cost of externalities per MWh (Table C2), we multiply these emission rates and the corresponding values of the health damages for each pollutant (for SO_2 and NO_x, for each region). The sum over the four regions is the per-MWh costs for SO_2 or NO_x.

We run these scenarios for MAPS for the years 2022 and 2026. The health damage values for 2022 and 2026 are directly from the estimates for these two years. The estimates for rest of the 2016 and 2032 are as follows. The values for 2022 are used for 2016-2022; the values for 2022-2026 are extrapolated; and the estimates for 2026 are used for 2027-2035.

[42] Thus, the results are specific to the 2014 CARIS database and will change when that database is updated. Because the database is confidential (although aggregate results are provided publicly), choosing this approach would require DPS Staff to repeat these steps for each update.

Gross values are the estimates based on the EPA's models, weighted by the MAPS emission rates. They do not reflect the compliance costs assumed in CARIS or energy and capacity cost forecasts. The net values of the health damage costs of SO_2 and NO_x and social cost of CO_2 (Table C3) are the net of these compliance costs assumed in CARIS.

We provide values at discount rates of 5 and 3 percent.[43] We use the GDP price deflator to convert EPA's SCC in to current dollars and a factor of 0.907184 to convert metric ton to short ton. The forecast for GDP price deflator for 2016-2026 was from the Blue Chip Economic Indicators, March 2015, and an annual rate of 2.1 percent is assumed for 2027-2035.

References

U.S. EPA (2010), Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 - Interagency Working Group on Social Cost of Carbon, February 2010.

U.S. EPA (2013a), Technical Support Document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors, January 2013.

U.S. EPA (2013b), Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 - Interagency Working Group on Social Cost of Carbon, May 2013.

U.S. EPA (2013c), User's Manual for the Co-Benefits Risk Assessment (COBRA) Screening Model, Version: 2.61, July 2013.

[43] We note the discount rate debate above, in the White Paper.

Table C-1. Social Cost of CO_2, 2015-2050 a (in 2011 Dollars per Metric Ton of CO_2)

Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th percentile
2015	$12	$39	$61	$116
2020	$13	$46	$68	$137
2025	$15	$50	$74	$153
2030	$17	$55	$80	$170
2035	$20	$60	$85	$187
2040	$22	$65	$92	$204
2045	$26	$70	$98	$220
2050	$28	$76	$104	$235

Source: EPA, http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

Table C-2. Gross Monetized Environmental Externalities

(Nominal Dollar per MWh)

	Discount Rate 5%				Discount Rate 3%			
YEAR	SO_2	NO_x	CO_2	TOTAL	SO_2	NO_x	CO_2	TOTAL
2016	54	5	9	67	57	5	29	91
2017	55	5	9	69	58	5	31	94
2018	56	5	9	70	59	5	32	97
2019	57	5	10	72	60	5	34	100
2020	58	5	10	73	62	6	35	102
2021	59	5	11	76	63	6	37	105
2022	61	5	11	77	64	6	39	109
2023	54	5	11	70	57	5	38	101
2024	47	5	11	63	50	5	38	93
2025	40	4	11	55	42	4	37	84
2026	33	4	11	48	35	4	37	75
2027	33	4	11	49	35	4	38	77
2028	34	4	12	50	36	4	39	79
2029	35	4	13	52	37	4	41	82
2030	36	4	13	53	38	4	42	84
2031	36	4	14	55	38	4	44	87
2032	37	4	14	56	39	4	46	90
2033	38	4	16	58	40	5	48	92
2034	39	4	16	59	41	5	50	95
2035	39	5	17	61	42	5	51	98

Table C-3. Net Monetized Environmental Externalities

(Nominal Dollar per MWh)

	Discount Rate 5%				Discount Rate 3%			
YEAR	SO_2	NO_x	CO_2	TOTAL	SO_2	NO_x	CO_2	TOTAL
2016	52	5	3	60	55	5	24	84
2017	53	5	2	60	56	5	24	85
2018	54	5	2	61	57	5	25	88
2019	55	5	2	63	59	5	26	90
2020	57	5	0	62	60	5	25	91
2021	58	5	0	63	61	6	26	93
2022	59	5	0	64	62	6	27	95
2023	52	5	0	57	55	5	27	88
2024	46	5	0	50	48	5	27	80
2025	39	4	0	43	41	4	26	72
2026	32	4	0	35	34	4	26	63
2027	32	4	0	36	34	4	26	64
2028	33	4	0	37	35	4	27	66
2029	34	4	0	38	36	4	28	67
2030	34	4	0	38	36	4	28	69
2031	35	4	0	39	37	4	29	71
2032	36	4	0	40	38	4	30	73
2033	36	4	0	41	39	5	31	74
2034	37	4	0	41	39	5	32	76
2035	38	4	0	42	40	5	33	78